Complete and Cost-Effective Approach for Diagnosing Formation Damage and Performing Successful Stimulation Operations

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Abstract

This paper presents and describes a comprehensive and cost-effective approach to diagnose and treat the formation damage problems. The proposed approach consists of systematic steps: recognition of the immediate problem; data collection, analysis and integration; identification of the source of the formation damage problem; assessment of the formation damage; identification of the proposed treatment techniques; evaluation of all options; selection of the best stimulation technique; stimulation process design, implementation of the plan; and evaluation and analysis of the results. Application of such approach in an oil producing well (case study from the Gulf of Suez area) of an international joint venture company in Egypt achieved oil production rate of 560 bbl/day after complete mud loses during the drilling operations. Such study is an original contribution to the knowledge of diagnosing and solving formation damage problems.

Keywords

Acidizing; Formation Damage; Acidizing Operation Design; Stimulation; Matrix Acidizing; Acidizing Treatment; Successful Stimulation Operations

Introduction

The formation damage can be described as any process that causes a reduction in the productivity of an oil and gas producing formation, or a reduction in the injectivity of a water or gas injection well [Civan, 2000]. The formation damage is categorized by the mechanism of its creation as either natural or induced as shown on Fig. 1 [Hill et al., 2000; Ali, 2011]. Natural damages are those that occur primarily as a result of producing the reservoir fluid. Induced damages are the result of an external operation that is performed on the well such as a drilling or injection operations.

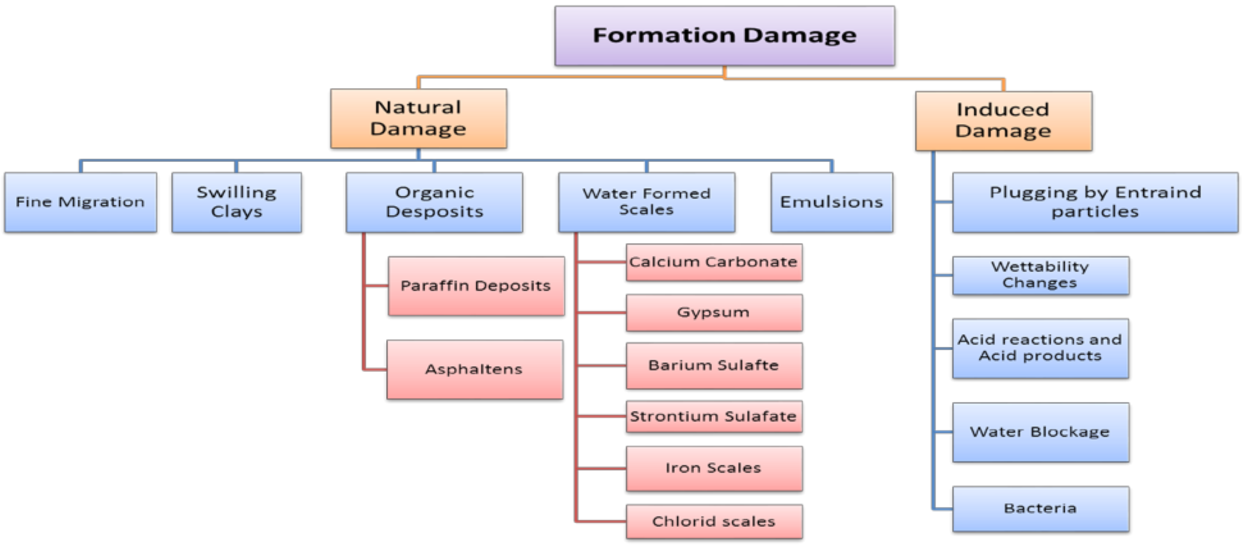

FIG. 1 FORMATION DAMAGE CLASSIFICATIONS

The stimulation processes are used to remove the formation damage and enhance the property value by the faster delivery of the petroleum fluid and/or to increase ultimate economic recovery.

Diagnosing and Solving of the Formation Damage Problems

The main objective of this work is to present a complete plan and cost-effective approach to diagnose and treat the formation damage problems. As shown in Fig. 2, the proposed plan incorporates the following steps:

1. Recognition of the immediate problem
2. Data collection, analysis and integration
3. Identification of the formation damage source
4. Assessment of the formation damage
5. Identification of the proposed treatment techniques
6. Evaluation of all options
7. Selection of the best stimulation technique
8. Stimulation process design
9. Implementation of the plan
10. Evaluation and analysis of the results

Recognition of the Immediate Problem

The formation damage problem is recognized, when the well is producing with low productivity relative to what they are capable of producing and then evaluating possible mechanical problems in these wells. Geology, petrophysics and reservoir engineering play important roles in quantifying the productive potential of a given well. Once a well is diagnosed as underperforming, the reasons must be determined.

Data Collection, Analysis and Integration

All available information on the well such as well logs and records, reservoir characteristics and information on the completion and previous workovers should be collected and analyzed. There are four main categories of data to study the reasons of the low productivity and/or low injectivity:

1. Wellbore data such as wellbore dimensions, deviation data, tubular and completion data
2. Reservoir data such as reservoir properties (pressure, temperature, etc.), rock properties, and lithology for the zone of interest
3. Reservoir fluids data such as fluid properties (viscosity, compressibility, density, etc.)
4. Well history data such as history of drilling, completion, stimulation, workover, injection, and withdrawal. The historical information is the key to identifying potential formation damage mechanisms.

All of these data must be assessed before damage mechanisms can be identified and/or treatments are recommended. Data collection, analysis and integration programs require a great deal of effort, scrutiny and innovation. The key steps are (1) plan and organize, (2) collect and analyze, and (3) integrate and store. This approach addresses a general framework of optimizing the data analysis process.

Identification of the Formation Damage Source

Once it has been established that a well is producing below its potential, an assessment must be made to determine the source of the problem: formation damage or mechanical problem. Once mechanical reasons are eliminated as a potential cause of poor production, the wells become stimulation candidates.

Diagnosis can be based on a (1) review of the well and field history, (2) analyses of samples of plugging material recovered from the field, and (3) knowledge of formation mineral and fluid (e.g., water and oil) properties, as well as pressure testing and logging evaluation [Wang, 2009].

Assessment of the Formation Damage Problem

Damage source identification is an essential task prior to treating fluid selection and treatment design. Damage is characterized using the results of the laboratory tests, logging techniques and well history. Detailed study is necessary to develop a list of suspected damages from the available data. Multiple types of damage are normally suspected and are all considered when designing the treatment. Formation damage identification and investigation include types of damage, location of damage, extent and screening of damage, and effect of damage on well production or injection [Allen, 1973; Beadie, 1995].

There are a few logging techniques available to estimate the invasion profile as a result of mud filtrate invasion, presumably causing formation damage. For a vertical well drilled with a conductive mud, an invasion profile may be computed from resistivity logs.

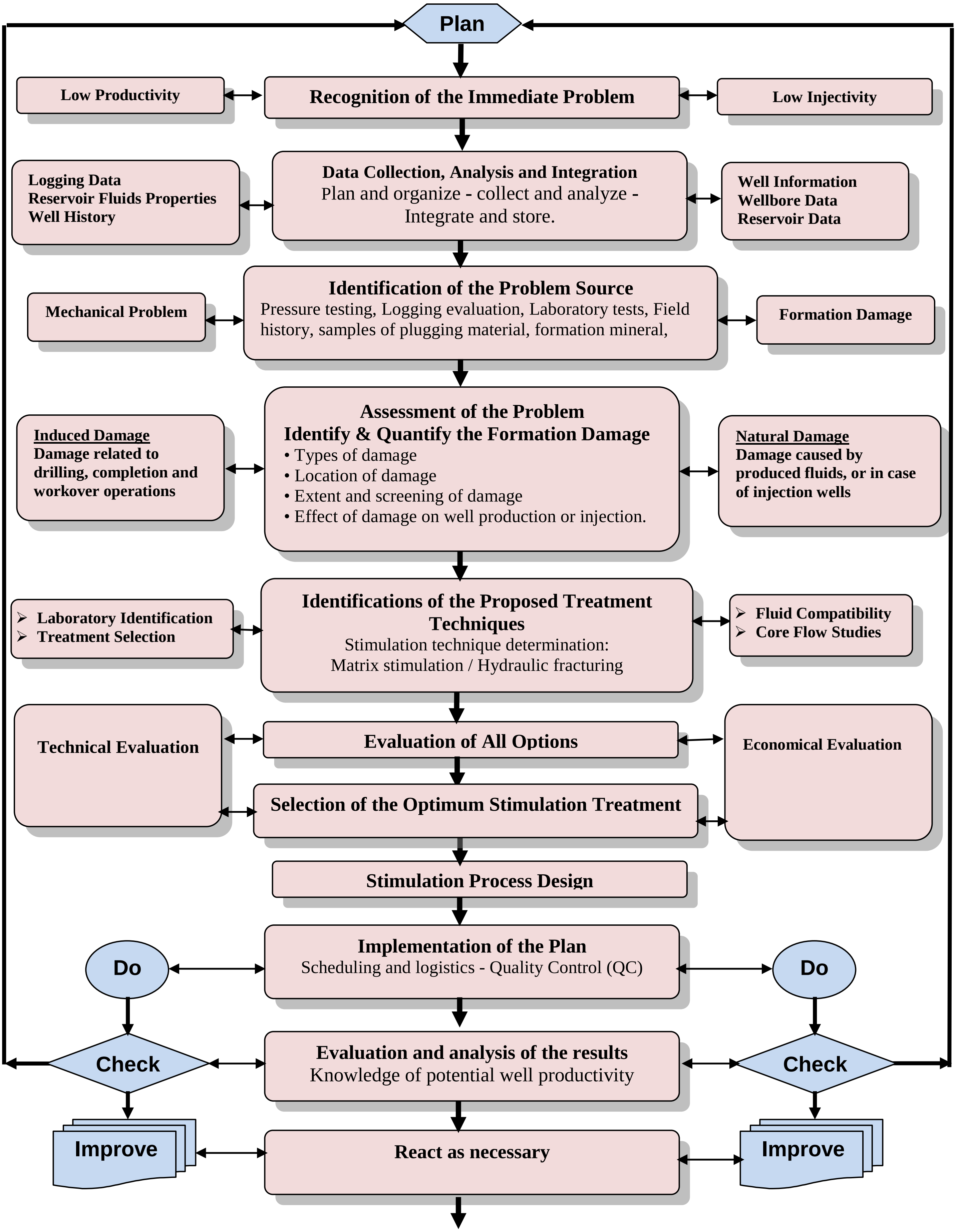

FIG. 2 PLAN FOR DIAGNOSING AND SOLVING OF THE FORMATION DAMAGE PROBLEMS

Resistivity logs provide resistivity measurements at several depths of investigation. Provided that there is a resistivity contrast between the mud filtrate and virgin formation fluid, each resistivity measurement reflects how much the formation fluid is displaced by mud filtrate. The resulting invasion profile does not strictly correlate with a drilling-induced damage profile, but it is a reasonable first-order estimate. This technique can be extended to non-vertical wells by including the effect of dip between the wellbore and the formation.

Another method to estimate the depth of invasion, and thus the drilling-induced damage profile, is the use of TDT (Thermal Decay Time) logs. These record the rate of decay of a thermal neutron population following an emission of high-energy neutrons by the down-hole generator. Some formation elements, primarily chlorine, have a very high capacity to absorb neutrons. Since chlorine is primarily associated with formation water, the TDT log resembles the usual open hole resistivity logs, and therefore gives an indication of the invasion profile.

In some cases, it may be useful to conduct laboratory compatibility tests of the completion or drilling fluids and the formation fluid or rocks. Such tests can help in developing understanding of the problem in the current well and lead to corrective action.

In many cases, it is not possible to characterize the formation damage completely. If the diagnosis is uncertain, it is recommended to prioritize the probable causes and design a treatment for the most probable scenarios.

Identifications of the Proposed Treatment Techniques

Once the cause of formation damage and the location of the damage are known, then one can select the optimum fluid and design the best treatment to remove the damage. Table 1 lists the damage types and remedial recommendations for comparison to the condition and characteristics of the candidate well [Ali, 2011].

The detailed analysis of formation cores is required to design the damage removal treatment. Conventional cores are recommended to complete the analysis because sidewall cores can be contaminated with drilling fluids and may not be representative of the formation. If sidewall cores are used, the analysis should be conducted on duplicate cores.

The formation mineralogy is an important parameter affecting stimulation success. Therefore, the analytical techniques (X-ray diffraction and thin-section analysis) are used to characterize the formation mineralogy.

Matrix treatments are usually used to remove the damage chemically, restoring a well to its natural productivity. Matrix stimulation is accomplished by injecting a fluid (e.g., acid or solvent) to dissolve and/or disperse materials that impair well production in sandstones or to create new, unimpaired flow channels between the wellbore and a carbonate formation. The most common matrix stimulation treatment is acidizing, in which an acidic solution is injected to dissolve minerals in the formation. More than 40,000 acid treatments are pumped each year in oil and gas wells [Ali, 2011]. These treatments typically involve small crews and minimal equipment. The next most common fluids are organic solvents aimed at dissolving waxes, paraffin, asphaltenes or other organic damaging materials.

In some instances, chemical procedures may not be effective or appropriate, and hydraulic fracture operations are used to bypass the damage. This is achieved by producing a high conductivity path through the damage region to restore wellbore contact with undamaged rock. Hydraulic fracture operations may be performed on a well for one (or more) of three reasons [Smith and Shlyapobersky, 2000]:

1. to bypass near-wellbore damage and return a well to its “natural” productivity
2. to extend a conductive path deep into a formation and thus increase productivity beyond the natural level
3. to alter fluid flow in the formation: In this case, fracture design may affect and be affected by considerations for other wells (e.g., where to place other wells and how many additional wells to drill). The fracture becomes a tool for reservoir management.

Hydraulic fracturing with acid (usually hydrochloric acid [HCl]) is an alternative to propped fractures in acid-soluble formations such as dolomites and limestone. The major difference between acid and propped fractures is that conductivity is obtained by etching the fracture faces instead of using a proppant to prevent the fracture from closing. Acid fracturing may be

TABLE 1 CAUSES OF FORMATION DAMAGE AND THE REMEDIAL RECOMMENDATIONS

Operation	Causes of formation damage	Accelerating factors	How to cure the damage
Drilling	- mud filtrate invasion - mud solids invasion - sealing of pores and flow tunnels by the troweling action of the bit, drill collars and drill pipes - plugging by rock cuttings	- high permeability formation - water-based mud - abrupt reduction in salinity - drilling with high water loss - bentonite mud - strongly overpressured drilling - high solids mud	- backflush - acid wash, matrix acidizing
Running casing and cementing	- plugging/blockage of pore space by mud or cement solids - filtrate invasion - chemical reactions with cement additives and spacers	- high-permeability formations	- deep perforations - matrix Acidizing, acid wash
Perforating	- plugging of perforations and formation with debris - compaction of pores around perforations	- use of low performance or expendable guns - perforate overbalanced in drilling mud	- backflow - acidizing
Running completion string	- plugging by solids from completion fluids and diverting agents - filtrate invasion - dissolution of rock cementing material	- overbalanced conditions with damaging completion fluids - improper bridging materials - high-permeability formation - uncleaned wellbore and production equipment	- acid treatment - solvent wash - same as for
Production	- fines movement - clay migration - condensate and water blockage - deposits of salt crystals, wax, and paraffin - hydrate and emulsions forming	- high production rates - increase in water/oil ratio - pressure decrease - communication with water zones - poor gravel-packing or sand-control measures	- acidizing - chemical treatments
Gravel packing	- invasion of filtrate from gravel-pack slurries - invasion of solids and contaminations - mixing of gravel with formation sand - plugging by diverting agents	- variation of permeability along the producing interval - nonuniform sand - clay-rich sand	- Acidizing (through the gravel pack) - replace the gravel pack
Acidizing	- insoluble precipitates - iron precipitation in the wellbore - plugging of solids coured from the tubing	- incompatibility between acid, acid additives and formation materials - damaging diverting agents - large variations in permeability	- re-acidize with proper additives
Fracturing	- plugging by formation fines or damaged by gelled frac fluids	- poorly designed frac	- soak with a gel breaker
Workover	- residual cement plugging - plugging by wireline loosened iron scale or paraffin from tubing - plugging by metallic particles resulting from casing repair operations - damaging workover fluids - damaging bridging materials	- operate at overbalanced conditions - high-permeability formation - large variation in permeability - uncleaned wellbore - use of corrosion inhibitors or emulsion breakers	- acid stimulation - chemical treatment

preferred operationally because the potential for unintended proppant bridging and proppant flow-back is avoided. However, designing and controlling the depth of penetration of the live acid into the formation and the etched conductivity are more difficult than controlling proppant placement. Acid penetration is governed by the chemical reaction between the rock and the fracturing fluid (as opposed to a simple mass balance in propped fractures), and conductivity is determined by the etching patterns formed by the reacting acid (as opposed to being a property of the proppant under a given stress). In both cases, acid fracturing introduces a dependence on rock properties that is not present in propped fracturing. In addition, the properties that acid fracturing design and control depend on are usually

more difficult to determine than other formation properties.

Evaluation of All Options

Because the whole purpose of stimulation is to increase the value of the producing property through an accelerated production rate or increased recovery, economics should be the driver in deciding whether to conduct the stimulation, what type of stimulation to do and which various aspects of the treatment to include.

Selection of the Optimum Stimulation Treatment

Selection of the optimum method should depend on the technical and economical evaluation of the previous fields' applications.

Stimulation Process Design

Most treatments are currently based on empirical rules of thumb. Key parameters in treatment design are the placement technique, chemical selection and soak time. Mechanical assemblies such as packers, bridge plugs, spring-loaded "spot control" valves and coiled tubing can be used to ensure proper placement. This is critical in minimizing the volume of treating fluid.

Treatment fluid selection is an important step in the engineering process. Multiple fluids (fluid systems), composed of base fluids and additives, are selected on the basis of lithology, damage mechanism and well condition. Each fluid in the treating schedule serves a special purpose. The main treating chemicals fall into the following categories [Thomas and Morgenthaler, 2000]:

- solvents to remove organic deposits (such as paraffin)
- oxidizers to remove damage from polymers
- scale removers to remove sulfate or oxide scales
- acids to remove carbonate and oxide scales, break polymer residues or stimulate carbonate formations
- hydrofluoric acid (HF) to remove aluminosilicate damage (primarily clays) from sandstone formations.

The pumping schedule includes the treating fluid and diverter sequence and the injection rate of each stage. It is generated using empirical rules based on previous field experience or computers.

Proper placement of the treatment fluid over the whole pay zone is required for successful treatment. Five main diversion techniques can be used to improve fluid placement in carbonate acidizing: packers, ball sealers, particulate diverters, foam diversion and self-diverting acid. In large intervals (e.g., horizontal wells) some of these techniques can be combined with the use of coiled tubing.

Implementation of the Plan

The scheduling and logistics along with the site preparation is the first step in the implementation of the treatment operation. Operational constrains and operation stimulation program are reviewed and considered. Materials must be monitored to ensure that they meet the specifications of the design, equipment must be maintained to perform properly, and personnel on site must understand and execute their assigned roles. Quality control (QC) testing and training should be documented as standard practices [Brannon et al., 1987].

Evaluation and Analysis of the Results

After implementing the treatment method, the production rate is regularly observed to realize the success rate of the recommended treatment method and to determine whether the formation damage problem was solved or not?

The analysis of the results of the treatment method indicates whether the treatment requires modification and helps to improve future designs in similar situations.

Case Study: Well I in Nukhul Formation

An international joint venture company in Egypt is currently progressing a development plan in the Gulf of Suez area. The company applied similar approach to solve formation damage problem in one of the development wells "Well I" in Nukhul formation. The recommended remedial actions succeeded to put the well on production with an oil production rate of 560 bbl/day after complete mud loses during the drilling operations. It should be highlighted that the author of this paper (who proposed the above mentioned approach) has not participated in the preparation and the execution of the acid stimulation job of the presented case study.

Well I was drilled to represent additional drainage point for Nukhul reservoir formation. Nukhul formation is characterized by the following:

- It is represented by conglomerates and beach deposits.
- It includes three main pay zones (Nukhul A, B, and C). Two interlayers, represented by strongly cemented siltstone, separate Nukhul A from Nukhul B and Nukhul B from Nukhul C. The uppermost fan sequence (Nukhul A) is capped by another strongly cemented siltstone interval.
- Formation temperature is 205°F.
- Formation pressure ranges between 2700 to 3000 psi at datum level (8600ft).
- Fracture gradient is 0.55 psi/ft.
- Wells history in the same area indicates that severe drilling fluid losses are occurred while penetrating the pay zones of Nukhul formation
- The average productivity of offset wells in Nukhul formation ranges between 400 to1000 bbl/d (65 to160 m3/day) with a water cut of 15%. (productivity index of the offset wells is about 1 bpd/psi)..

During the drilling of Well I with oil base mud, it was observed that severe drilling fluid losses were occurred while penetrating the pay zone. Therefore, loss of circulation material was pumped to control the mud losses. Unfortunately, the mud losses were continued and the decision was taken to side track the well. Well I was drilled and completed with a measured depth of 11942 ft (3640 m). The well logs (Fig. 3) indicated that Well I had a sand net thickness of about 328 ft (100 m) in Nukhul formation. However, the well was completed with total perforation intervals of 150 ft (46 m) in 5′ liner.

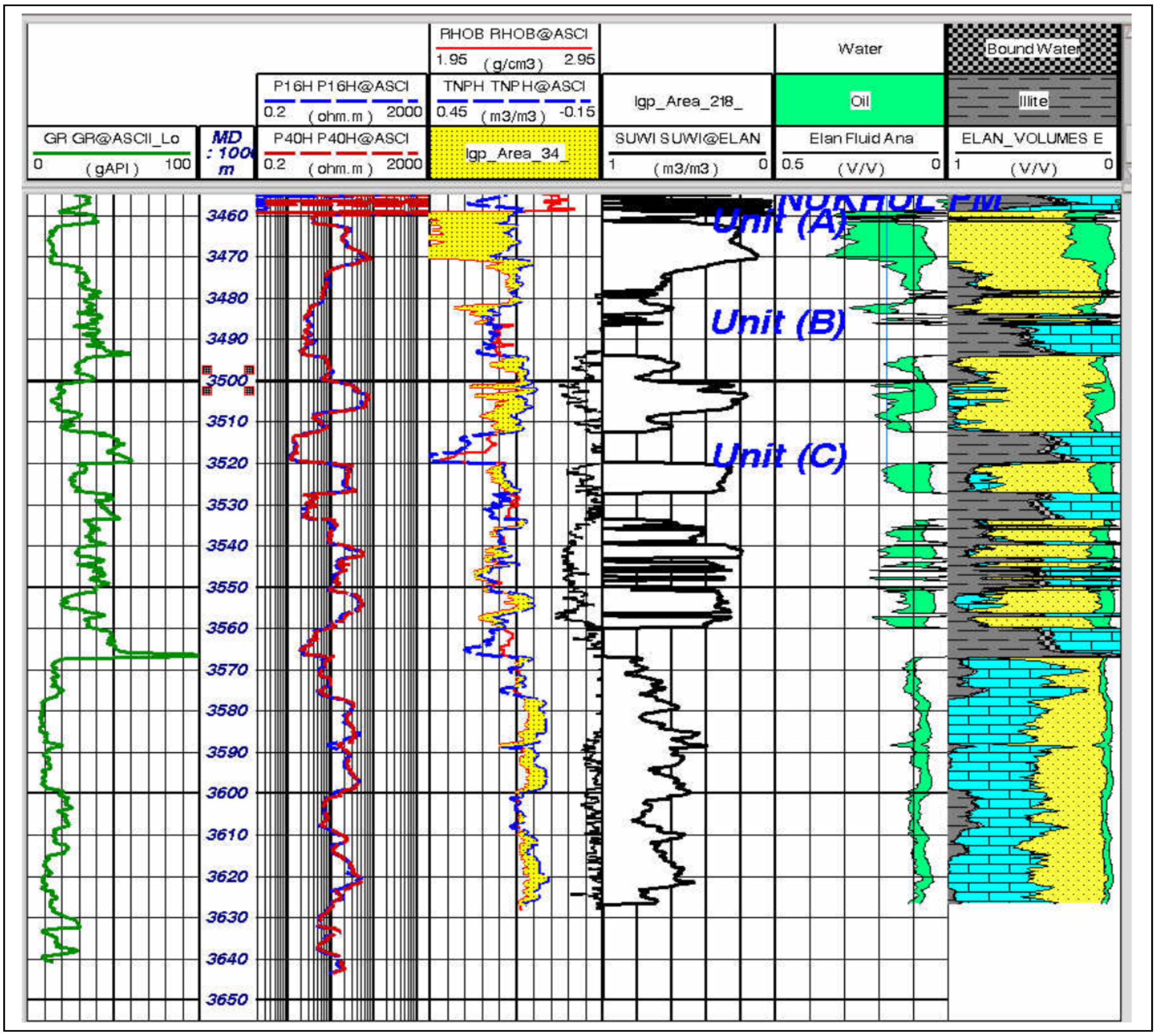

FIG. 3 WELL LOGS OF WELL I

TABLE 2 PRODUCTIVITY INDEX OF NUKHUL FORMATION IN WELL I

No	Interval	layer	h_{perf}	$h_{net\ perf}$	$h_{vertical}$	$h_{vertical}$	Ø	$K_{Correlation}$	Kh	P.I.	Completion factor	$P.I._{cor}$
	Meter		Meter	Meter	Meter	ft	%	md	md.ft	bpd/psi	Fraction	bpd/psi
1	3462-3472	A	9	9	4.5	14.8	14.5	97.5	1440	0.441	0.25	0.110
2	3494-3498	B	14	4	2	6.6	16	217.0	1424	0.436	0.25	0.109
3	3498-3501			3	1.5	4.9	10	34.0	167	0.051	0.25	0.013
4	3501-3508			7	3.5	11.5	17	295.6	3394	1.039	0.25	0.260
5	3520-3525	C	7	4	2	6.6	19	548.4	3598	1.101	0.25	0.275
6	3525-3527			2	1	3.3	16	217.0	712	0.218	0.25	0.054
7	3540-3544	C	8	3	1.5	4.9	19	548.4	2699	0.826	0.25	0.207
8	3544-3548			1.5	0.75	2.5	21	1017.4	2503	0.766	0.25	0.192
9	3552-3555	C	8	3	1.5	4.9	14	117.0	576	0.176	0.25	0.044
10	3555-3560			3	1.5	4.9	18.5	469.9	2312	0.708	0.25	0.177
Total			46	39.5	19.8	64.80				5.8		1.4

h_{perf} : Gross perforated thickness (measured thickness)

$h_{net\ perf}$: Net perforated thickness (measured thickness)

$h_{vertical}$: Net perforated thickness (vertical thickness – well inclination is about 60°)

Ø : Formation porosity from the logging

$K_{Correlation}$: Formation permeability (obtained from the porosity/permeability plot of the formation)

P.I. : Productivity index

Completion Factor : It is a correction factor to adjust the calculated P.I. It considers the effect of the completion in the productivity of the formation. It is estimated from the actual data of the offset wells in the same formation.

$P.I._{cor}$: Corrected productivity index

The productivity index of Nukhul formation in Well I was theoretically calculated as shown in Table 2. It was found that the estimated productivity index was about 1.4 bpd/psi which was too close to the average productivity index of Nukhul formation in the offset wells. However, the analysis of the vacuum test (which was performed during the completion of the well) showed that the well productivity index was only about 0.5 bpd/psi. This may be attributed to the presence of formation damage in the area around the wellbore due to the mud losses during the drilling operations of Well I. Accordingly, after review the wells history in the same area, the decision was taken to perform acid stimulation job to remove the formation damage due to the mud losses.

Table 3 presents the core experiment analysis of Nukhul formation. This table demonstrates the possibility for acidizing of Nukhul formation.

Nukhul formation is mostly sandstone rock with cementing material of dolomite mineralogy which would react with treating acid favoring in cleaning and regaining enhanced permeability for the formation. Therefore, the nitrified 15% HCl was selected as the main treating acidizing fluid. The nitrified acid was selected to work as diversion for the long perforation interval. This can get improvement by enlarging pore size.

The acidizing program was generated using empirical rules based on previous field experience in Nukhul formation. The acidizing program included injection of 8000 gal of the nitrified 15% HCl acid. The main additives were as follows:

- Acid corrosion inhibitors (2% - 160 gal): it is composed of polar organic compounds capable of adsorbing onto the metal surface, thereby establishing a protective film that acts as a barrier between the metal and the acid solution.Surfactants (0.5% - 40 gal): it was used to break undesirable emulsions, reduce surface and/or interfacial tension, and speed clean up.

TABLE 3 CORE EXPERIMENT ANALYSIS OF NUKHUL FORMATION

Potential formation damage of mineral components				
Sensitive mineral	**Potential problem**	**Avoid using**	**Use**	**Treatment to eliminate problems**
Carbonates	Calcium-fluoride and iron-hydroxide	HF acid, oxygen-rich systems	HCl or acetic acid, oxygen scavengers	Acidize with HCl and use suitable chelating agent.
Pyrite	Iron-hydroxide precipitate sulfate production	Oxygen-rich systems, fluid contain Ca+2, Sr+2, Ba+2	Acid systems, oxygen scavengers	Acidize with HCl/HF and use correct flushes
Kaolinite	Migration of fines	High flow rates and high transient pressures	Low flow rates and low transient pressures	Use a clay stabilizer
Silicates (clays and feldspars)	Silica	Concentrated HF	Dilute HF	Acidize with HCl/HF and use correct flushes
Mixed-Layer Illite/Smectite	Swelling/iron-hydroxide precipitate	Fresh-water system/oxygen-rich system, high pH	KCL or hydrocarbon system	Acidize with HCl/HF and use suitable chelating agent

Anti-sludge agent (1% - 80 gal): when acid contacts some crude oils, sludge can form at the acid/oil interface. As a result, the sludge accumulates in the formation and decreases the formation permeability. To combat the formation of sludge, cationic and anionic surfactants were used to adsorb and provide a continuous layer of protection at the acid/oil interface.

- Clay stabilizer (10 gal/Mgal – 80 gal): it was used to prevent the damage that may occur from the swelling of the clay.
- Mutual solvents (5% - 400 gal): it is chemical that is mutually soluble in both hydrocarbons and water. Mutual solvents were used to
  - ✓ aid in reducing water saturation around the wellbore by lowering the surface tension of the water to prevent water blocks
  - ✓ aid in providing a water-wet formation to maintain the best relative permeability to oil
  - ✓ help to prevent stabilizing emulsions
  - ✓ help to maintain the required concentration of surfactants and inhibitors in solution by reducing adsorption of these materials
  - ✓ dissolve any oil on the formation pore surface
  - ✓ serve as a de-emulsifier
- pH control (3% - 240 gal): it was used so that a low pH is maintained after the HCl is spent. A low pH aids in preventing the secondary precipitation of iron.
- Iron sequestering agents (50 lb/Mgal – 400 lb): these agents bond to the iron and hold it in solution so that it cannot precipitate.

The treatment fluid was displaced into the formation with 6500 gal of foamed sea water and surfactant. Surfactant helps to reduce the surface tension and capillary pressure of the fluid for better improved fluid recovery. This over-flush would displace the spent acid into the formation for improved results (Improve the clean-up of spent acid following treatment).

Fluid placement is critical to the success of the matrix stimulation treatment. In the acidizing job of Well I, a combination of employing coiled tubing and foam as diverting agents were used. Coiled tubing was used to spot the fluids along the zone, while reciprocating the tubing along the zone of interest.

To evaluate the acidizing job of Well I, vacuum test was performed after conducting the acidizing

program. Fig. 4 shows a comparison between the results of the vacuum tests before and after the acidizing job.

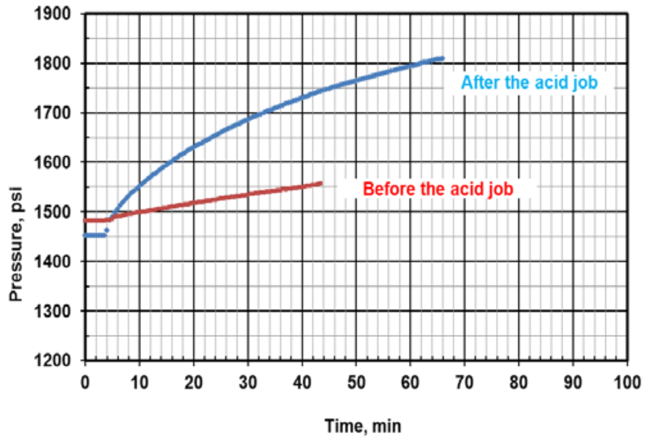

FIG. 4 VACUUM TESTS RESULTS BEFORE AND AFTER THE ACID JOB IN WELL I

It is clear from Fig. 4 that, after the acid job, the pressure intends to stabilize faster. This is an indicator for achieving better formation productivity and successful and effective acid job. The analysis of the vacuum test results showed that the well productivity increased from about 0.5 bpd/psi to 1.0 bpd/psi after the implementation of the acid job. When the well was put on production, the oil production rate was 560 bbl/day and water cut of 2%.

Conclusions

A comprehensive and cost-effective approach to diagnose and treat the formation damage problems is proposed. Application of such approach in oil producing well at Gulf of Suez area in Egypt achieved oil production rate of 560 bbl/day after complete mud loses during the drilling operations. The results of this case study was presented and analyzed.

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